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# Improve Waterflood Efficiency by Film Treatment Technology

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**Abstract**

In the process of reservoir water-flooding development, the injected water of sodium sulfate type and calcium, barium and strontium ion in high salinity formation water combine to form slightly-soluble sulfate scale, result in low efficiency of water injection system and reduction of water-flooding swept volume. In view of above problems, nanofiltration (NF) will be a main driver in injection water treatment. It removes $SO_4^{2-}$ in injected water, reduces scale ion content from the source, achieves the purpose of scale inhibition and control, and increases water-flooding efficiency. Lab and field trials indicate that the NF treatment has a favorable result. The removal rate of $SO_4^{2-}$ reaches 85.0%, scale inhibition efficiency is 80.2% and the injection profile of injected well increases 1.95m. The study creates a new way for preventing and treating sulfate scale (especially strontium sulfates scaling ), increasing waterflood sweep efficiency and improving injection system efficiency.



*Key words:* nanofiltration treatment; barium sulfate; water-flooding efficiency

## 1. Introduction

Oilfield water injection method to maintain formation energy and improve oil recovery has been widely used at home and abroad. However, sodium sulfate, the only water source of oilfield injection, is full of $SO_4^{2-}$ ions. The scale, especially strontium barium sulfate scale, is easily produced by the reaction

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between $SO_4^{2-}$ ions and $Ca^{2+}$, $Ba^{2+}/Sr^{2+}$ in formation water, and it is practically insoluble in any inorganic acids and other solvents. The scale, which is hard to remove and difficult to relieve by adding agents, brings great harms to production, such as formation plugging, rise in injection pressure, lower in flooding efficiency and reduce in waterflood sweep area.

In recent years, polymer membrane, a representative of membrane separation technology which is applied to fluid separation unit operation has made tremendous development. As one of the main water and other liquid separation film, reverse osmosis (RO) and nanofiltration (NF) play an important role within the field. NF is one of membrane separation technology between reverse osmosis (RO) and ultrafiltration (UF) which has charges on the surface, nanoscale pores and kinds of materials, such as: selective removal of divalent, high ions and material with molecular weight more than 200 Da. However, it has a considerable price of salt permeability, due to price can freely go through the plasma membrane, the osmotic pressure caused by different ion concentrations on both sides of the membrane is lower than reverse osmosis. The required operating pressure of NF membranes is lower than RO and the general operating pressure of NF is 0.5 ~ 1.5Mpa.

Special separation effect makes NF technology in unique advantages on classification of low molecular organics and removal of inorganic salts, heavy metals, microorganisms, colloids and virus. Moreover, it is widely used in water treatment including drinking water preparation and deep purification, seawater softening, industrial wastewater treatment, and landfill leachate treatment, and so on. Plummer [3] takes NF-40 membrane for water injection. It makes the removal rate of $SO_4^{2-}$ reached 98%, which can prevent the pore plugging form the deposition of high concentrations of $Ba^{2+}$ in formation water. Davis [4] takes the softened seawater by NF as the injection water for British North Sea oilfield in order to prevent the formation plugging from the deposition of barium sulfate in Brea wells.

Up to now, there hasn't been any report about the application conditions that NF water treatment technology have on scale control in onshore oilfield. In this paper, NF membrane has been adopted for treating the sodium sulfate injection water in one oilfield in order to remove parts of scaling $SO_4^{2-}$ ions and reduce the scaling ion contents from the job starts. As a result, the removal rate of $SO_4^{2-}$ was 85.0%, scale inhibiting rate was more than 80%, and the injection profile and waterflood efficiency have been increased. The barium sulfate scaling problems by poor compatibility of waterflooding is settled thoroughly in the way given in the paper. Furthermore, the study presents important reference for increasing injection swept volume and improving waterflood efficiency.

## 2. Lab experiment study

### *2.1. Experimental Principle*

The injection water contains high amounts of anion which have poor compatibility with formation water and mineral properties. Scaling will be produced which declines the reservoir flow capacity and takes great can harm to oil production. Therefore, compatibility of injection water and reservoir must be studied.

Dynamic compatibility study is designed to simulate the formation temperature and reservoir state at the time of waterflooding, and takes the high temperature/pressure core flow meter for constant displacement below the critical velocity. The flow tests are designed on petroleum industry standard SY / T 5358-2002 [5]. The test is used to evaluate the influence of water on water phase permeability water when the water with different sources inject into the core sample in proportion.

The average relative permeability is introduced to compare the core flow capacity in order to directly compare the water phase permeability changes of core samples. The value of average relative permeability is the dimensionless quantity. The calculation is:

$$K\,rw = K_l / K_g \qquad (1)$$

(1) where: $K_l$ - core average liquid test permeability,$10^{-3}\mu m^2$;
$K_g$-core absolute permeability,$10^{-3}\mu m^2$;
$K_{rw}$- the average of core average relative permeability, a decimal.
The nearer the average relative permeability value closes to 1, the less the permeability loss is.
Test pressure: 16MPa, test temperature: 60℃.

### 2.2. Water quality analysis

In this paper, the water samples were obtained from one oilfield water injection station. The water quality analysis results were in Table 1.

Table 1. Water quality analysis results ( mg/l)

| Water sample | $K^+$+$Na^+$ | $Ca^{2+}$ | $Mg^{2+}$ | $Ba^{2+}$ | $Cl^-$ | $CO_3^{2-}$ | $HCO_3^-$ | $SO_4^{2-}$ | Total salinity |
|---|---|---|---|---|---|---|---|---|---|
| Injection water | 620 | 266 | 421 | 0 | 1620 | 6 | 173 | 1240 | 4346 |
| Filtered water | 185 | 16 | 34 | 0 | 269 | 0 | 26 | 174 | 704 |
| Formation water (Chang 4+5) | 38000 | 9910 | 902 | 1560 | 79200 | 0 | 128 | 0 | 129700 |

Table 2. Damage condition of core permeability before/after nanofiltration treatment

| Water quality | Well | Gas rmeability (mD) | Porosity (%) | Core relative damage rate (%) | Core average relatively damage rate (%) |
|---|---|---|---|---|---|
| Injected water: formation water = 2 : 8 | A-163-33 | 1.6591 | 12.05 | 29.71 | 34.70 |
| | A-170-30 | 6.8316 | 12.95 | 27.11 | |
| | A-159-42 | 1.6424 | 14.18 | 22.58 | |
| | A-177-19 | 0.5029 | 12.02 | 54.44 | |
| | H-163 | 1.1466 | 14.01 | 39.68 | |
| nanofiltration water: formation water =2:8 | A-163-30 | 1.6591 | 11.34 | 34.14 | 25.51 |
| | A-170-30 | 15.7363 | 14.18 | 10.19 | |
| | A-159-42 | 1.2485 | 13.57 | 20.92 | |
| | A-177-19 | 0.3683 | 12.12 | 38.53 | |
| | H-163 | 1.0646 | 13.52 | 23.79 | |

### 2.3 Evaluation of different water fouling

Table 2 shows the results of core water phase permeability damage by different injection water quality. Comparison of the test results suggest that : when the ratio of NF water to formation water is 2:8, the core relative damage rate was less than the ratio of injection water to formation water was 2:8. It is chiefly because the scaling tendency of injected water and formation water is greater than of the NF water and formation water.

### *2.4 Changes of interfacial tension*

The interfacial tension has been tested before and after NF treatment. Table 3 shows that the surface tension of injected water has little change after NF treatment, but the interfacial tension has dropped one time.

The flow capacity of fluids in reservoir porous medium can be described by dimensionless function of the ratio between driving force and capillary drag force. It is, in essence, the capillary number. The capillary number of water- movement system is determined by the following formula:

$$Nc = \frac{V\eta_w}{\delta_{ow}}\left(\frac{v_o}{v_w}\right)^2\left(\frac{\eta_w}{\eta_o}\right)\exp\left(-\frac{|V_{op}-V|}{10V_{op}}\right) \qquad (2)$$

where $Nc$ - the capillary number, $v_o$ -oil flow velocity, $v_w$ -water flow velocity, $v$ -the displacing phase velocity; $\eta_w$ - the displacement phase (water) viscosity, $\delta_{ow}$ -the oil-water interfacial tension. Formula (2) shows that fluids' flow capacity in porous media relating to fluid viscosity, oil-water interfacial tension and flow velocity.

Table 3. Surface / Interfacial tension variation before / after NF treatment

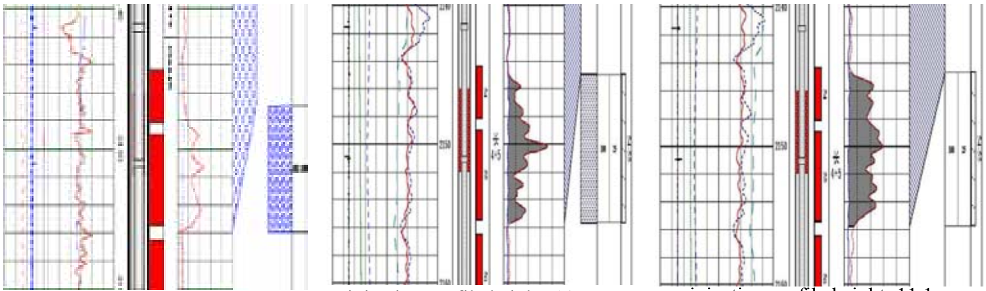
| Name | Surface tension ($mN\cdot m^{-1}$) | Interfacial tension ($mN\cdot m^{-1}$) |
|---|---|---|
| Injection water | 73.85 | 49.44 |
| Nanofiltration water | 71.31 | 22.01 |

At the end of waterflooding period, the capillary number is usually maintained at $10^{-6}$-$10^{-7}$ .The fluids' flow capacity can be improved by reducing the oil-water interfacial tension and increasing the fluid viscosity and flood w rate of flow velocity. After NF treatment, the oil-water interfacial tension has reduced one time and capillary number has increased. This is equivalent to an increase in permeability channel of formation and an improvement in waterflood efficiency.

## 3. Field test

A suit of NF industrial equipment with a daily processing capacity of 300$m^3$ /d had been applied at one water injection plant. The system had run into trial operation in the end of March 2009. The water injection plant has 8 injection wells with a total injection allocation rate of 215 $m^3$/d. Among them, there are 5 wells in layer Chang 4+5 with injection allocation rate of 110 $m^3$/d and 3 wells in Chang 2 layer with injection allocation rate of 105$m^3$/d. Until now, the experiments have been running smoothly for 2.5 years. The injection profile was tracked respectively before and after the field test. The results indicated that water profile had been increased and waterflood efficiency had been improved after the NF treatment.

Figure 1 described the injection profile variations of × × - × well at different time period. On April 23, 2009, the injection profile height was 9.0m. On June 11, 2010, the injection profile height was 10.7m. On Nov. 11, the injection profile height was 11.1m. Figure 1 pointed out that with an increase in the injection time, the injection profile height before and after NF treatment had increased by 2.1 m in test well × × - ×. It just tells the water absorbing ability of the formation has increased and waterflood sweep efficiency has improved after the NF treatment.



injection profile height : 9.0m injection profile height: 10.7m injection profile height: 11.1m

Figure 1. Injection profile variations of × × -× well

## 4. Conclusion

(1) Core damage evaluation tests illustrates the injected water has poor compatibility with formation water which can cause damage to the reservoir. However, NF effluent has better compatibility with formation water which takes less damage to reservoir.

(2) The injection profile of 2 water waterflood well with NF treatment indicates the injection profile height of two wells has a different increasing tendency in both before and after experiments. It just tells waterflood sweep efficiency has increased after NF treatment.

(3) The interfacial tension of injected water has reduced and capillary number has increased by NF treatment, which is useful to improve waterflood efficiency.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